Scientia Iranica C (2011) 18 (6), 1407–1414

SCIENTIA IRANICA

Sharif University of Technology

Scientia Iranica

Transactions C: Chemistry and Chemical Engineering

www.sciencedirect.com

Research note

Optimal conditions for immiscible recycle gas injection process: A simulation study for one of the Iranian oil reservoirs

S. Mohammadi [a,*], **R. Kharrat** [b], **M. Khalili** [c], **M. Mehranfar** [d]

[a] *Department of Chemical and Petroleum Engineering, Sharif University of Technology, Tehran, P.O. Box 11155-9465, Iran*
[b] *Tehran Petroleum Research Center, Petroleum University of Technology, Tehran, Iran*
[c] *Petroleum University of Technology, Ahwaz, Iran*
[d] *Department of Chemical and Materials Engineering, University of Alberta, Edmonton, Alberta, Canada*

Received 5 January 2011; revised 21 June 2011; accepted 10 October 2011

KEYWORDS
Immiscible gas injection;
Oil reservoirs;
Simulation;
Optimum;
Sensitivity.

Abstract Immiscible gas injection is one of the most common enhanced oil recovery methods used under various reservoir conditions. In this work, the immiscible recycle gas injection, as an EOR scenario for improving recovery efficiency in one of the south-west Iranian oil reservoirs, is simulated by a commercial simulator, ECLIPSE. The reservoir fluid is light oil, with an API of 43. The oil bearing formations are carbonate, and so a dual porosity/dual permeability behavior was chosen for better representation of the fracture system. Different sensitivity analyses with respect to several parameters like the number and location of injection/production wells, production/injection rate, completion interval etc., are performed. It has been observed that in conjunction with the number of wells, 1 injection/2 production well pattern was the most efficient case. Also, the well oil production rate of 200 SM^3/Day and the well bottom-hole pressure of 75 bar provided higher oil recovery. Completion of injection wells in fracture and production wells in matrix have better oilfield efficiency in comparison to other cases. Finally, we proposed optimum conditions for the immiscible recycle gas injection in this reservoir, which maximizes oil recovery efficiency.

1. Introduction

In conventional oil recovery projects, the decline of primary production to an uneconomic level led to the development of various schemes to improve oil recovery efficiency before the abandonment of a reservoir. The term 'Enhanced Oil Recovery' (EOR) principally refers to the recovery of oil by any method beyond the primary stage of oil production. It is defined as the production of crude oil from reservoirs, through processes taken to increase the primary reservoir drive. These processes may include pressure maintenance, injection of displacing fluids or other methods, such as thermal techniques. Therefore, by definition, EOR techniques include all methods that are used to increase the cumulative oil produced (oil recovery) as much as possible [1].

Enhanced oil recovery can be divided into two major types of technique: thermal and non-thermal recovery. Non-thermal recovery methods can be split into: water flooding, gas injection (including LPG miscible slug, enriched gas miscible processes, high pressure lean gas miscible processes carbon dioxide processes) and chemical processes (including micellar polymer flooding, caustic flooding, polymer flooding). Thermal recovery refers to oil recovery processes in which heat plays a principle role. The most widely used thermal techniques are in situ combustion, continuous injection of hot fluids, such as steam, water or gases, and cyclic operations, such as steam soaking [1].

In gas injection processes, there are two main types of gas injection: miscible and immiscible. In miscible gas

* Corresponding author.
E-mail address: saber_mohammadi1365@yahoo.com (S. Mohammadi).

Peer review under responsibility of Sharif University of Technology.

doi:10.1016/j.scient.2011.10.003

Production and hosting by Elsevier

ELSEVIER

Table 1: Initial reservoir conditions.

Initial reservoir pressure	168 bar
Reservoir temperature	120 °F
Initial water–oil contact	3200 ft S.S
Initial gas–oil contact	1850 ft S.S

Table 2: Physical properties of reservoir oil.

Bubble point pressure (bar)	API	Viscosity (cp)
135.2	43	0.56

Table 3: Constraints in simulation.

Minimum BHP	25.4 bar
Maximum GOR	800 scf/STB
Maximum WCT	50%
Production life	15 year

injection, the gas is injected at or above Minimum Miscibility Pressure (MMP), which causes the gas to be miscible in the oil. On the other hand, in immiscible gas injection, flooding by gas is conducted below MMP. This low pressure injection of gas is used to maintain reservoir pressure to prevent production cut-off, and thereby increase the rate of production [1]. The combination of light crude, relatively high reservoir temperature and relatively low reservoir pressure favors immiscible gas injection as the most suitable EOR process [2]. Previous studies have shown that immiscible crestal gas injection has the potential to increase oil recovery by the following mechanisms:

- An alternate reservoir energy source can be created in the secondary gas cap to diminish the effects of the aquifer. Pressure increase on the crest can slow or neutralize the advance of water.
- Gas displaces oil more efficiently than water. The end-point recovery by gas is 50%, compared to 30% by water.
- Vertical displacement of oil by gas, with gravity segregation forces, will add to the incremental recovery.
- Oil swelling and viscosity reduction will contribute to improved oil recovery [3].

Injection of a fluid, such as water or gas, under appropriate conditions, has become the usual practice to recover additional oil after primary production. These methods, commonly known as secondary recovery methods, usually recover 5%–20% of remaining oil after primary production. However, these fluids, being immiscible with reservoir oil, leave high residual oil saturation (40%–60% OOIP) after displacement. Gas recycling has been recommended for several years as a favorable production scenario for pressure maintenance, as well as producing unrecovered oil reserves. Typically, in this method, a number of injection wells are drilled and a fraction of produced field gas or gases from other resources is injected into the reservoirs.

In this work, we used a commercial simulator, ECLIPSE, to simulate immiscible recycled gas injection in a specific sector, which is a quarter of one of the most important Iranian south-west oil reservoirs. The phase behaviour of the reservoir fluid was modeled by the PVTi module of the ECLIPSE package, using Peng-Robinson EOS. In the simulated model, after history matching of the production data and also reservoir pressure, some sensitivity analyses, with respect to the location and number of wells and injection/production parameters, were performed. Finally, optimum conditions for gas recycling in this reservoir were proposed.

2. Reservoir properties

The reservoir fluid is light oil, with an API of 43, supplied from one of the Iranian south-west oil reservoirs. The initial state of the reservoir and properties of the reservoir fluid, as well as constraints that should be applied, are presented in Tables 1–3.

3. Model description

In this simulation study, the reservoir has been modeled with commercial software, ECLIPSE. Cartesian coordinates with corner point geometry were selected for construction of the model. Dual porosity and dual permeability behaviour were chosen for better representation of the fracture system. Use of a fully implicit pressure solution method was agreed upon. The grid model and properties are shown in Figure 1 and Table 4, respectively.

3.1. Production data

The Original Oil In Place (OOIP) was calculated by IRAP software to about 1400 million barrels, with abandonment pressure to be 105.5 bar. This figure was confirmed by simulation software giving a value of 1379 million barrels. The cumulative production by 2001 was about 155 million barrels.

3.2. PVT data

Precise and accurate characterization of a reservoir fluid is an imperative factor in reservoir simulation studies. In gas flooding processes, because of the existence of a great interaction between injected and in place fluids, it is very important to characterize the reservoir fluid precisely. PVT experiments are usually expensive and time consuming, and are performed under limited conditions. Therefore, EOS based PVT packages are used widely for the prediction and evaluation of fluid properties in well and surface conditions over a wide range of temperatures, pressures and composition. Here, using a PVTi module of ECLIPSE, three-parameter Peng-Robinson EOS which predict the behavior of Iranian reservoir fluid quite well were tuned to present the fluid sample of the reservoir. Lohrens–Bray–Clark (LBC) was used as viscosity correlation. For the entire reservoir, just one composition was considered. Amongst different available PVT samples, the one that better described the behavior of the reservoir fluid and better accorded with real data was taken as the reservoir fluid representative. Components defined in PVTi and EOS were tuned without any grouping, since in a non-compositional run, no grouping is needed. The results of the tuning process for liquid density, liquid viscosity and oil relative volume that will be used in this study are given in Figures 2–4, respectively. After inserting the petrophysic, PVT and initialization data in the model, and also the rock-type determination of the grids (that depends on the grid porosity and initial water saturation), the model is ready for various studies. In this study, the locations for the production wells, A, B, C and D, are known at the beginning of the production. It should be mentioned that all well configurations are vertical.

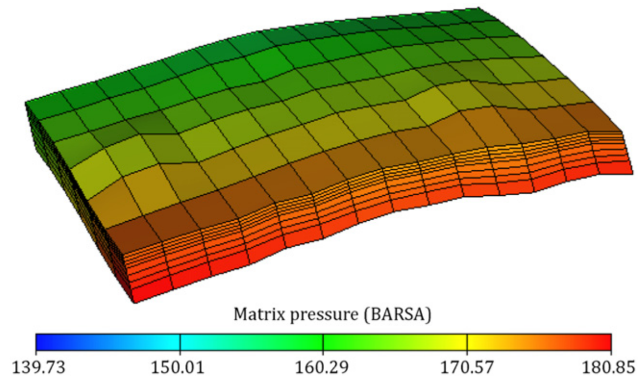

Figure 1: Static model of the reservoir constructed by a simulator.

Table 4: Reservoir characterization in the simulation.

No of cells in X direction (N_X)	6	Grid size in Z direction (D_Z, m)	5
No of cells in Y direction (N_Y)	14	K_X (md)	51
No of cells in Z direction (N_Z)	8	K_Y (md)	51
Grid size in X direction (D_X, m)	177	K_Z (md)	42
Grid size in Y direction (D_Y, m)	177	Porosity (percent)	12.35

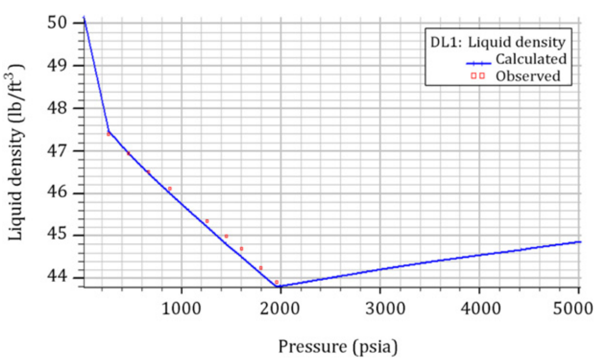

Figure 2: Comparison of calculated and observed oil density.

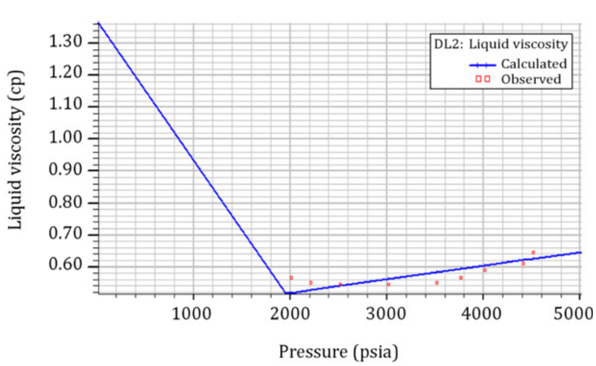

Figure 3: Comparison of calculated and observed oil viscosity.

4. Results and discussion

4.1. Natural depletion

This sector of the reservoir continued producing from year 1935 up to 2005, when the producing wells shut down. The following information is available from field production data during natural depletion:

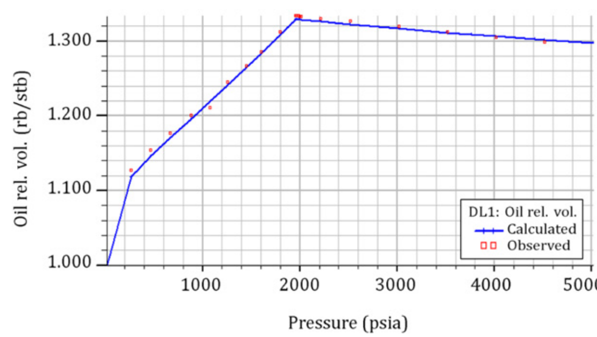

Figure 4: Comparison of calculated and observed oil relative volume.

- The sector ultimate oil recovery in natural depletion was 39.85% after 70 years of oil production.
- Initial reservoir pressure was around 168 bar and, finally, after 70 years of oil production, it reduced to 36.6 bar. At early production times, the field pressure rate decreased sharply.
- During this production scenario, the field initial production rate is around 5000 bbl/day. Around year 1977, two production wells shut down, and from year 1992, two other production wells started to produce from this sector. In 2005, these two wells also shut down. There is a sharp decline of oil production rate from year 1996.
- During the natural depletion period, the average GOR of this sector is about 2500 SCF/STB.
- This sector produced negligible water during the natural depletion interval.

Based on the above descriptions, this sector is a good candidate for EOR processes after 30 years of oil production. Therefore, we study the immiscible gas recycling scenario in this reservoir.

4.2. Immiscible recycle gas injection scenario

Here, the method of immiscible recycle gas injection has been simulated. This production strategy has resulted in better efficiency and therefore higher oil recovery and good

Table 5: Number of wells and field oil efficiency.

Number of wells	Maximum FOE	Average field pressure (bar)
1 PRO	0.46	29.00
Recycling-1INJ/1PRO	0.50	89.70
Recycling-1INJ/2PRO	0.66	83.50
Recycling-1INJ/3PRO	0.68	83.50
Recycling-2INJ/1PRO	0.50	90.30

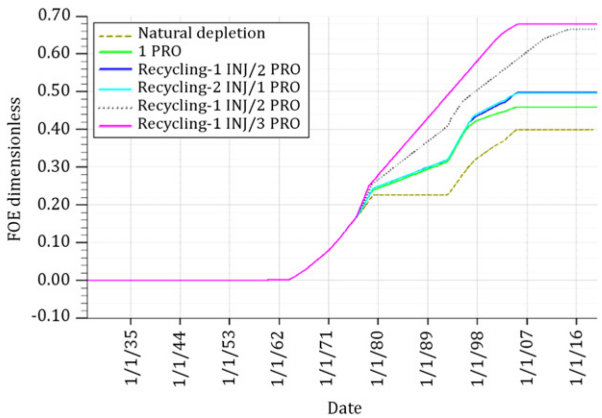

Figure 5: Field oil efficiency for different numbers of wells.

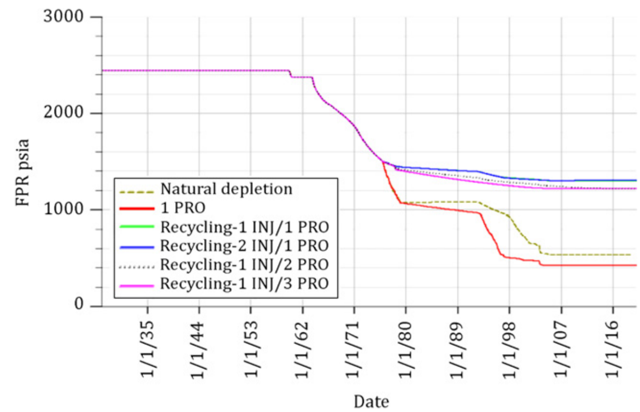

Figure 6: Field pressure for different numbers of wells.

economics. The simulation results illustrate the influences of immiscible recycle gas injection on recovery efficiency. In this scenario, the field produces naturally until 2005. We implement the EOR scenario from year 1976, because of the reservoir pressure decline. Some issues are considered as follows.

4.2.1. Sensitivity analysis with number of wells

In this section, we use a different number of wells with different configurations; in each configuration of which the best is selected for comparison with others. We have investigated the effect of the number of wells on the efficiency of both natural depletion and gas recycling mechanisms. By increasing the number of wells, the recovery factor increases. If the recovery factor is stable by increasing the number of wells, the optimum number of wells is obtained. Some of the best different cases that are selected for evaluating the influence of the number of wells on recovery are given in Table 5 and Figures 5 and 6. From the results, the 1-injection/3-production pattern has the highest efficiency and after that, the 1-injection/2-production pattern is the most efficient case. However, in the first case, the fluctuation in the GOR of producing wells is high. Thus, we choose case 1-injection/2-production as the most favorable in this part.

4.2.2. Effect of well pattern on oil recovery efficiency

Optimum performance can be achieved with the patterns defined in Table 6, by controlling the rates of injectors and producers. These calculations can be performed analytically, if we assume the displacing and displaced fluids are incompressible, the mobility ratio is one, and the reservoir has uniform properties. Note that the location of the injection wells was optimized by different factors, such as permeability, transmissibility, porosity and oil saturation distributions. By considering the mentioned factors, we try different patterns in this sector for optimizing well locations for the previous section (1-Injection/2-Production). Different configurations are presented in Table 7. Also, the field oil efficiency of different configurations is presented in Table 8. By comparison of different configurations, we propose configuration no 2, which has a higher performance than the other cases.

Table 6: Producer/injector ratios for common well patterns.

Well pattern	Producer/injector ratio
Four-spot	2
Five-spot	1
Direct line-drive	1
Staggered line-drive	1
Seven-spot	1/2
Nine-spot	1/3

Table 7: Well locations.

Configuration no	Inj-01		Prod-01		Prod-02	
	i	*j*	*i*	*j*	*i*	*j*
1	20	46	20	48	20	56
2	20	53	20	46	20	59
3	20	53	20	46	20	51
4	17	54	20	48	20	56
5	15	52	20	47	18	54
6	20	52	15	47	15	57
7	20	46	19	50	20	52

Table 8: Field oil efficiency for different well locations.

Configuration no	FOE
1	0.666
2	0.680
3	0.652
4	0.666
5	0.540
6	0.432
7	0.576

4.2.3. Sensitivity analysis on injection–production parameters

4.2.3.1. Sensitivity analysis on production rate. Here, we check different production rates for both wells (PRO-01 and PRO-02). The results are shown in Table 9 and Figure 7. From the table, we can see that the two cases WOPR = 350 SM^3/Day and WOPR = 200 SM^3/Day have higher efficiency in comparison to the other cases. But, with WOPR = 350 SM^3/Day, the instability in the

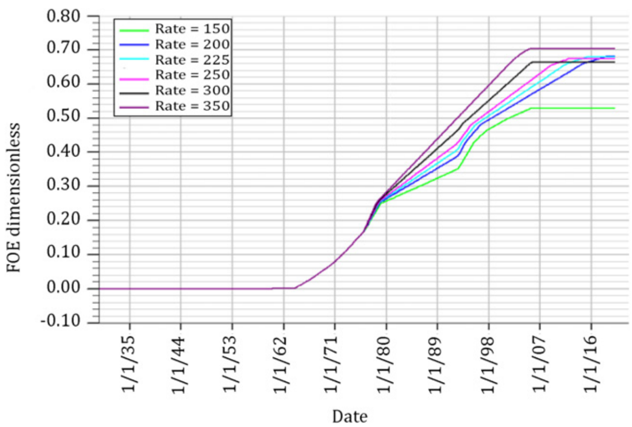

Figure 7: Field oil efficiency for sensitivity analysis on rate.

Table 9: Sensitivity analysis on production rate.

Rate (SM^3/Day)	FOE
150	0.528
200	0.682
225	0.680
250	0.676
300	0.664
350	0.704

GOR of both wells is very high, in respect to cases of WOPR = 200 SM^3/Day. Also, in the second case, the well produced up to year 2019, whereas in the first case (WOPR = 350 SM^3/Day), the well shut down in year 2005. Thus, in this part, we suggest the case in which WOPR is 200 SM^3/Day.

4.2.3.2. Sensitivity analysis on production Wells Bottom HolePressure (WBHP). We selected six different cases to investigate the effect of bottom-hole pressure on recovery efficiency (presented in Table 10). Generally, a higher bottom-hole pressure, as a constraint for controlling production, leads to more oil residue in a reservoir, thereupon reducing the recovery factor. By optimizing this parameter, the value of 75 bar was selected as an optimum well bottom-hole pressure. At this WBHP, FOE has the maximum value as shown in Table 10.

4.2.3.3. Sensitivity analysis on injection rate. One of the most important concerns in gas injection processes is the stability of displacement, because under unfavorable conditions, unstable

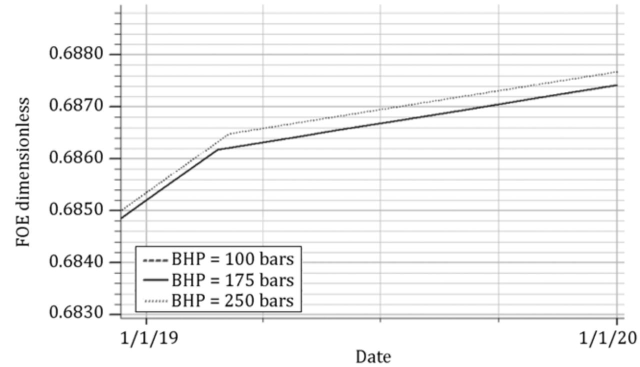

Figure 9: Field oil efficiency for sensitivity analysis on injection well BHP-close up view.

Table 10: Sensitivity analysis on production well bottom hole-pressure.

Case	WBHP (bar)	FOE
1	15	0.6826
2	25	0.6821
3	50	0.6848
4	75	0.6864
5	100	0.4980
6	150	0.4860

displacement will lead to poor macroscopic (volumetric) sweep efficiency. Two natural phenomena that cause unstable displacement and jeopardize volumetric sweep efficiency are gravity override and viscous fingering. In this part, the effect of gas injection rate on recovery is investigated. We change this parameter with a different injection fraction, which is defined in item 6 of the "GCONINJE" keyword for the injection well [4]. These fractions and the respective FOE are listed in Table 11. The simulation results from this study indicate that the injection scheme of case 4 of produced gas is the best development scheme. However, we should consider that this case, in which the produced gas is totally re-injected into the reservoir, is idealistic. We continue the rest of the sensitivity analysis using this value.

4.2.3.4. Sensitivity analysis on injection pressure. In this part, the effect of injection pressure on oil recovery has been studied. Simulation runs have been conducted with injection pressures of 100, 175 and 250 bar. Figure 8 shows field oil efficiency curves for different conditions. As seen in Figures 8 and 9, for

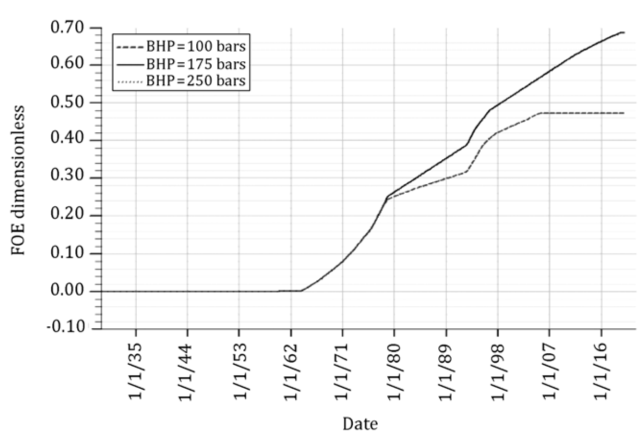

Figure 8: Field oil efficiency for sensitivity analysis on injection wells BHP.

Table 11: Sensitivity on injection rate.

Case	Re-injection fraction	FOE
1	0.25	0.484
2	0.50	0.508
3	0.75	0.528
4	1.00	0.686

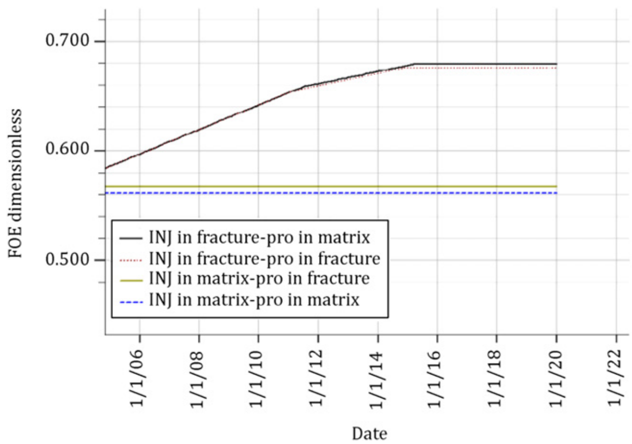

Figure 10: Field oil efficiency for sensitivity analysis on completion interval-close up view.

injection pressures of 100, 175 and 250 bar, final oil recoveries are 47.25%, 68.72% and 68.80%, respectively. Between two cases of 100 bar and 250 bar, there is a significant increase in final oil recovery, but by increasing injection pressure from 175 to 250 bar, the FOE increment is not sensible. It can be understood that for injection pressures higher than 175 bar, displacement front pressure reaches minimum miscibility pressure. It is clear that incremental oil recovery, due to miscible injection, is significant. However, the marginal increase in oil recovery, as a result of injection at pressures higher than 175 bar, may not compensate for additional equipment and operating costs at higher pressures. Thus, for this part, a bottom hole pressure of 175 bar will be proposed.

4.2.3.5. Sensitivity analysis on completion interval. Oil recovery efficiency depends strongly on the completion interval of injection and production wells. Since this oil field is a fractured reservoir, we simulate this sector by the dual-porosity, dual-permeability option of the ECLIPSE simulator. To complete the

Table 12: Location of injection and production wells.

Well name	Configuration			
	i	j	k_1	k_2
Inj-01	20	53	9	13
Pro-01	20	46	2	5
Pro-02	20	59	2	5

wells, we can complete injection and production wells in the matrix and fracture parts of the reservoir. We try this under different conditions. At first, we complete injection wells in fracture and production wells in matrix, and then try this conversely. For the third case, we complete both injection and production wells in the matrix, and finally complete them in fracture. Results of this part of the simulation have been shown in Figure 10. As shown in the figure, completing the injection well in fracture and production wells in matrix has better field oil efficiency. Completion of injection wells in matrix causes injected gas or fluid to move swiftly toward fracture and results in low sweep efficiency. However, if we complete injection wells in fracture, the injected fluid or gas sweeps the unrecovered oil in a better shape, and results in a better areal/volumetric sweep efficiency. Thus, we select the completion of injection wells in fracture and production wells in matrix in this section.

4.3. Optimum immiscible recycle gas injection conditions

Finally, during different parts of this work, we propose optimum conditions for the immiscible recycle gas injection implemented in this sector. Optimum well numbers are one injection well (Inj-01) and two production wells. Locations of these wells are listed in Table 12. Parameters of production and injection are given in Table 13. Optimum results of simulation are presented in Figures 11–15 in comparison with natural depletion.

5. Conclusions

The following conclusions can be drawn from this work:

- Immiscible recycle gas injection can be a good candidate as an EOR scheme for implementation under various reservoir conditions.
- Location of the injection/production wells was optimized by different factors, such as permeability, transmissibility, porosity and oil saturation distributions.

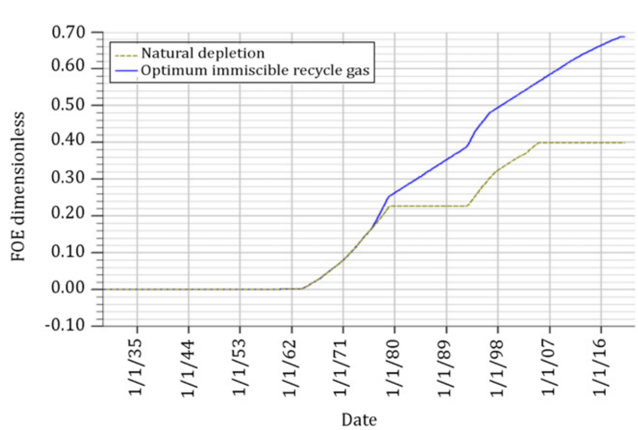

Figure 11: Field oil efficiency of optimum EOR conditions in comparison with natural depletion.

Table 13: Parameters of production and injection.

Maximum BHP of injection well (bar)	175
Minimum BHP of production wells (bar)	75
Production rate of production wells (SM^3/Day)	200
Injection well control mode	GRUP (item 4 in keyword WCONINJE)

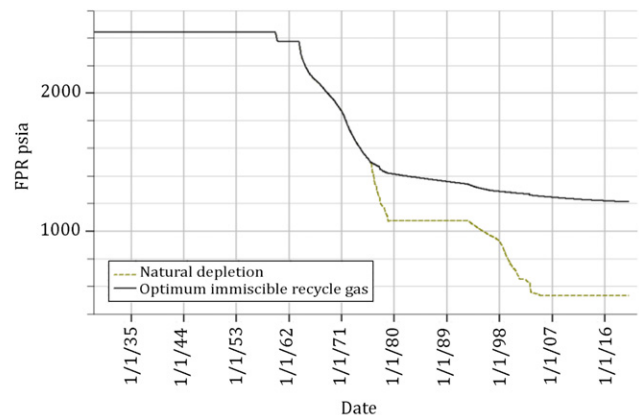

Figure 12: Average field pressure of optimum EOR conditions in comparison with natural depletion.

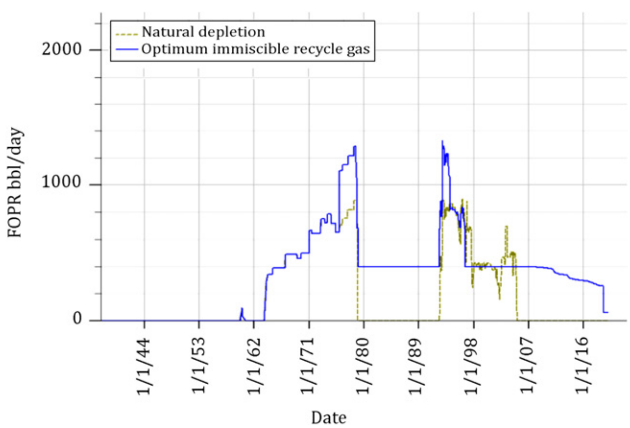

Figure 13: Field oil production of optimum EOR conditions in comparison with natural depletion.

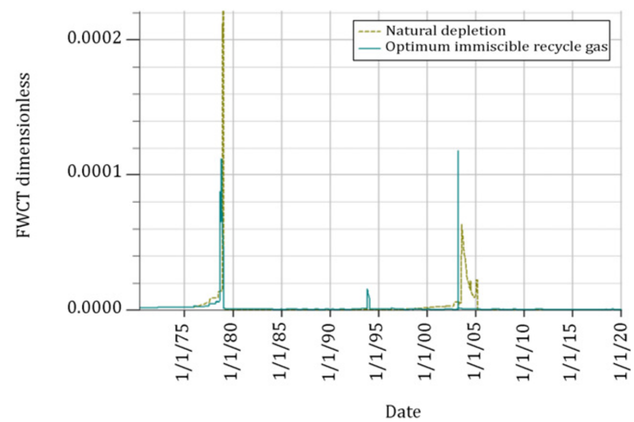

Figure 15: Water cut of optimum EOR conditions in comparison with natural depletion.

- After sensitivity analysis, two production wells and one injection well have been proposed as the optimum number of wells for this sector of the reservoir.
- Generally, for completion of the injection well, it is more efficient to select the intervals in the well with more fracture density while this should be proceeded inversely in the case of production well completion.
- The gas injection rate was found to have considerable effects on reservoir recovery: By reducing the gas injection rate, the recovery factor also decreases.
- It has been shown that the recovery factor of 39.85% during natural depletion has increased to about 68.72% during gas recycling.
- Reservoir communication and lateral connectivity are important elements in demonstrating the feasibility of any gas flooding development plans; interference test must be performed between wells of the reservoir to demonstrate pressure and fluid communication between available wells.
- The present study was an immiscible process. So, for finding miscibility conditions, several slim tube displacement experiments should be performed.

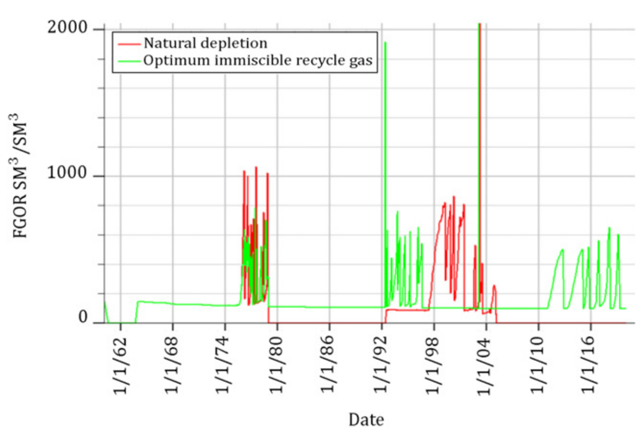

Figure 14: Field gas oil ratio of optimum EOR conditions in comparison with natural depletion.

References

[1] Al-Anazi, B.D. ''Enhanced oil recovery techniques and nitrogen injection'', *Canadian Society of Exploration Geophysicists Recorder*, pp. 28–33 (2007).
[2] Selamat, S., Teletzke, F., Patel, D., Darman, N. and Suhaimi, A. ''EOR: the new frontier in the Malay Basin development'', IPTC 12805, *International Petroleum Technology Conference*, Kuala Lumpur, Malaysia, December 3–5 (2008).
[3] Welch, V.S. ''Case history of an immiscible gas injection pilot in a massive carbonate reservoir with water drive'', Paper SPE 15760, Fifth SPE Middle East Oil Show, Manama, Bahrain, March 7–10 (1987).
[4] Eclipse Simulation Software Manuals, version-2009.1, Schlumberger (2009).

Saber Mohammadi holds a B.S. degree from the Petroleum University of Technology and an M.S. degree from Sharif University of Technology (all in Reservoir Engineering) where he is now a Research Assistant. Previously, he was involved in industrial projects at the Idea Center of Research Institute of the Petroleum Industry. His academic experience includes research on experimental and simulation studies of different EOR processes in heavy oil reservoirs, micro-scale transport phenomena and micro-model experiments. He has especially focused on shaly heavy oil reservoirs and application of nanoparticles in heavy oil recovery.

He has authored/co-authored more than 20 technical papers which have been presented and/or published in international conferences and journals. He is a member of SPE and EAGE.

Riyaz Kharrat holds B.S., M.S. and Ph.D. degrees from the University of Kansas, all in Chemical Engineering. He is Associate Professor of the Petroleum University of Technology (PUT) in Tehran and Director of the Petroleum University of Technology Research Center. He is currently involved in different research programs in Enhanced Oil Recovery (EOR), thermal recovery methods, and reservoir modeling and simulation.

He has previously served as Dean of the Ahwaz Faculty, Dean of Graduate Studies, and Dean of Research. He has authored/coauthored more than 200 technical papers which have been presented and/or published in international conferences and journals. In addition, he has published several books in enhanced oil recovery, applied mathematics and modeling in chemical and petroleum engineering.

Dr. Kharrat is an active member of The Society of Petroleum Engineers (SPE), and is currently serving as Chairperson and Director for the Iran Section.

Mohammad Khalili holds M.S. and B.S. degrees from the Petroleum University of Technology, Ahwaz, Iran, all in Reservoir Engineering, and is now a Petrophysicist at the National Iranian South Oilfields Company (NISOC) in Ahwaz. He previously worked as a Process Engineer at NISOC, where he is currently involved in national projects. His main research interests include reservoir characterization and simulation, production optimization and EOR methods optimization. He is an active member of SPE.

Mahsa Mehranfar received a B.S. degree in Chemical Engineering from Amirkabir University of Technology, in Iran, and is now Research Assistant at the Chemical and Materials Engineering Department at the University of Alberta, Edmonton, Canada. Her research interests are modeling and simulation of flow through porous media, oil sands and nano-scale structures. She has presented/published some technical papers at international conferences and in high ranking journals. She is a member of the Canadian Society of Chemical Engineering.